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July 22, 2004

Ms. Magalie R. Salas
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Via e-filing

Re: **California Energy Commission Staff Comments to the Federal Energy Regulatory Commission on Scoping Document 1 for the National Environmental Policy Act Review of PacifiCorp's Klamath River Hydroelectric Project, FERC No. 2082**

The California Energy Commission Staff (Energy Commission Staff) is pleased to submit to the Federal Energy Regulatory Commission (FERC) the following comments on Scoping Document 1 (SD1) for the National Environmental Policy Act (NEPA) review of PacifiCorp's Klamath River Hydroelectric Project, FERC Project No. 2082.

The California Energy Commission is California's lead energy information agency. The attached comments from Energy Commission Staff are intended to bolster the evidentiary record by ensuring that the characterization and assessment of energy-related issues are done properly, in accordance with the best energy data and analytic methods. These comments on SD1 build on previously submitted comments, including Energy Commission Staff comments on the Final License Application (April 26, 2004), and the Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project (May 2003).

Energy Commission Staff comments are offered in the context of the Klamath River being one of the most important remaining salmon rivers in California, which provides significant habitat through most of its length for endangered runs of Chinook and coho salmon and steelhead trout. The Klamath's salmonid fisheries are regionally significant in biological, economic, tribal, social and cultural terms. The Klamath Hydroelectric Project's lower dams preclude access to fully 300 miles of mainstem and tributary salmonid habitat.

The Energy Commission Staff's primary recommendation to FERC for the NEPA analysis of the project and the proposed alternatives is that a series of decommissioning alternatives be developed and fully evaluated. At a minimum, we propose that two dam removal scenarios be prepared for study; 1) removal of Iron Gate Dam and addition of volitional fish passage upstream; and 2) removal of all California dams and powerhouses, and addition of volitional fish passage upstream. For the Oregon dams, we recommend that FERC consider input from Oregon agencies and stakeholders regarding the formulation of alternatives for potential decommissioning of dams in

Oregon. Energy Commission Staff believe that full or partial decommissioning may be a viable option because the Klamath Hydroelectric Project is a small energy facility with 161 MW of nameplate capacity and average annual production of 656 GWh. Low power – high impact energy facilities such as the Klamath Hydroelectric Project can create net environmental benefits if decommissioning proves to be feasible and cost-effective, and if replacement energy is available.

Energy Commission Staff provide guidance and numerous references on energy supply-demand balances that are intended to create the appropriate analytic framework for conducting the Need for Power analysis. New generation resources (including renewables), conservation and energy efficiency measures will be needed over the next few years in California, and in the 2010-12 time period in the Pacific Northwest, in order to maintain electric resource adequacy. The resource needs will vary for individual load serving entities, such as PacifiCorp. These new generation resources and conservation measures are already cost-effective and commercially viable, and generally less environmentally damaging than the Klamath Hydroelectric Project. In the view of Energy Commission Staff, the amounts of Klamath Project energy and capacity that would need to be replaced are small in comparison to the additional energy and conservation resources needed to meet long-term load growth. It is reasonable to expect that replacement power, energy, and ancillary services can be procured by the load serving entity (PacifiCorp) in the timeframes that are appropriate to maintain industry reliability standards.

Energy Commission Staff also offer two energy plans to FERC for consideration as Comprehensive Plans. These are the 2003 Integrated Energy Policy Report, prepared by the California Energy Commission, and the Energy Action Plan, prepared jointly by the California Energy Commission, California Public Utilities Commission, and California Power Authority.

The Energy Commission looks forward to continued participation in the upcoming phases of FERC's relicensing process for the Klamath Hydroelectric Project. If you have any questions on the comments, please contact Jim McKinney of my staff at 916-654-3999 (jmckinne@energy.state.ca.us).

Sincerely,

TERRENCE O'BRIEN, Deputy Director
Systems Assessment and Facility Siting Division

Attachments

CC: Mr. Toby Freeman,
Hydro Licensing Director, PacifiCorp

Mr. Michael Chrisman
Secretary, California Resources Agency

Mr. Ryan Broddrick
Executive Director, California Department of Fish and Game

Ms. Celeste Cantu
Executive Director, California State Water Resources Control Board

SCOPING OF ENVIRONMENTAL ISSUES FOR NEW LICENSE

PACIFICORP'S KLAMATH RIVER HYDROELECTRIC PROJECT FERC NO. 2082

CALIFORNIA ENERGY COMMISSION STAFF COMMENTS TO THE FEDERAL ENERGY REGULATORY COMMISSION ON SCOPING DOCUMENT 1

July 22, 2004

Part I – Introduction and California Energy Commission Authorities and Interests

Introduction

The California Energy Commission Staff (Energy Commission Staff) is pleased to submit to the Federal Energy Regulatory Commission (FERC) the following comments on Scoping Document 1 (SD1) for PacifiCorp's application to relicense its Klamath River Hydroelectric Project, FERC No. 2082 (Project). SD1 presents the list of issues proposed for examination by FERC staff and its contractors under the National Environmental Policy Act (NEPA). These written comments compliment and supercede the oral comments provided by Energy Commission Staff to FERC in Redding, California on May 20, 2004.

The Energy Commission Staff's comments are intended to bolster the evidentiary record of the proceeding by ensuring that the characterization and assessment of energy-related issues are done properly, in accordance with the best available energy data and analytic methods.

Summary of Previous Energy Commission Staff comments

These comments build on comments submitted to FERC by Energy Commission Staff on PacifiCorp's Final License Application on April 26, 2004. The main points in the April 26 comment letter included:

1. The Klamath River provides regionally significant habitat for endangered runs of Chinook salmon, coho salmon and steelhead trout;

2. Fully 300 miles of mainstem and tributary salmonid habitat could become available to Klamath River salmonids if the barriers to passage created by the lower project dams, beginning with the Iron Gate Dam at river mile 190, were removed;

3. Due to the Project's low energy values (161 MW nameplate capacity and 656 GWh average annual production) and the significance of the Klamath River fisheries, partial and full decommissioning alternatives should be developed and fully evaluated in accordance with NEPA;

4. PacifiCorp establishes the Klamath Hydro Project's annual energy value at $70 per megawatt-hour (MWh) and $48.5 million annually. Energy Commission Staff cannot confirm that these figures are appropriate for use as the critically important valuation estimate for the project's energy. PacifCorp's valuation method does not appear to conform to FERC regulations, nor to guidance issued in the 1995 Mead Paper Decision.

Energy Commission Staff comments on the Final License Application included by reference the findings from the 2003 ***Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project***[1] (Energy Assessment). Key findings from the Energy Assessment included:

- From the perspective of potential impacts to electric resource adequacy, the Energy Commission Staff believes that potential decommissioning of some or all of the Klamath Project is a viable project alternative that should be evaluated by FERC during the relicensing process. Energy facilities with low power values and high levels of environmental impact can create important restoration benefits if decommissioning proves to be cost-effective, feasible, and if alternative power resources are available. The Klamath project is a small energy facility with 161 MW total capacity and annual average production of 656 GWh. Loss of some or all of this capacity and energy should not significantly affect PacifiCorp's ability to provide electricity to its 1.6 million customers.

- PacifiCorp is currently a net importer of energy, and secures 28% of its electricity through power purchase agreements. PacifiCorp may face a 4,100 MW shortfall by 2014 if their existing long-term power purchase agreements are not renewed and if no additional generation is secured. The scale of the Klamath Project is small compared to the scale of additional generation, transmission and demand side resources needed to meet load forecasts, reserve margins and transmission system reliability. Consequently, it is likely that decommissioning would not have a significant reliability impact on a regional scale.

- Replacement energy may be available locally and regionally, as demonstrated by several local generation projects. A 484 MW natural gas cogeneration plant and a 93 MW combustion turbine peaker project were recently built in Klamath County, Oregon. Energy from this project will be sold to California municipal utilities. In addition, two new combined cycle

[1] *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, California Energy Commission Staff Report, Publication No. 700-03-007, May 2003.

projects in Klamath County totaling about 1,600 MW are undergoing licensing review by the Oregon Department of Energy. These projects are also intended to serve other contract obligations in California. The 543 MW Klamath Energy Project is expected to be licensed by the end of 2004, while the 1,150 MW COB Energy Facility Project is now in the evidentiary phase of its licensing review.[2] Replacement energy would likely cost more than the energy from the Klamath Hydroelectric Project.

- The Energy Commission's Energy Assessment is a preliminary study. For potential decommissioning, additional study is needed to assess local reliability issues, to determine the overall benefits, identify costs and risks to stakeholders and the environment, and define an appropriate decommissioning strategy.

California Energy Commission Authorities

The California Energy Commission is California's lead energy information agency. Under the Warren-Alquist Act, the Energy Commission is charged with the collection, analysis, and dissemination of detailed information concerning "all forms of energy supply, demand, conservation, public safety, research, and related subjects."[3] In this regard, the Energy Commission employs a full-time staff with expertise in relevant matters such as analysis of electricity power supply, demand, price and related issues.

The Energy Commission has exclusive jurisdiction for certifying all thermal power plant sites and related facilities in California with installed capacity of 50 megawatts (MW) or more. The Energy Commission's power plant siting program is fully certified under the California Environmental Quality Act (CEQA) by the California Resources Agency.[4] Accordingly, the Energy Commission employs a full-time staff with expertise in a wide range of environmental and energy issues pertaining to large power plants and related facilities throughout the State of California. In carrying out its mandates, the Energy Commission is responsible for balancing the need for a reliable electricity supply system with the equally important need to protect environmental quality.[5]

The Energy Commission's legal authorities and responsibilities were expanded in the fall of 2002 when the California Legislature passed the Integrated Energy Policy Act (Senate Bill 1389). This Act directs the Energy Commission to prepare a biennial ***Integrated Energy Policy Report*** (Energy Report) for submission to the Governor and Legislature. The Act also states that information

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[2] *Energy Facility Siting Council Announcements and Notices Page*, Oregon Department of Energy Website, http://www.energy.state.or.us/siting/announce.htm, consulted April 19, 2004.

[3] California Public Resources Code (PRC) Sections 25216.5(d) and 25309.3(c).

[4] PRC Section 25500 *et seq.,* and Title 14, CCR, Section 15251(k).

[5] PRC Section 25001.

contained in the Energy Report will form "the foundation of energy policies and decisions affecting the state."[6]

One of the findings in the first ***Energy Report,*** issued in December 2003***,*** concerns hydroelectricity:

> "Hydroelectricity has historically played an important role in meeting California's electricity needs. Its low production costs and unique ability to meet critical peak demand have long benefited the state's ratepayers. Some hydroelectric projects unfortunately have serious environmental consequences such as significant, ongoing impacts to many California rivers and streams, native salmon and trout populations, and the water quality needed to support sustainable riverine ecosystems. … Since the FERC licensed most of the state's hydroelectric facilities more than 30 years ago, these facilities were not subject to current environmental standards. By 2015, 44 FERC-licensed projects in California will seek renewals, affording the state the rare opportunity to address problems with existing fisheries and aquatic resources. In addition, decommissioning of high environmental impact hydroelectric facilities that supply little power is a possible method of restoring important aquatic habitat."[7]

Part II – Energy Commission Staff Technical Comments on Scoping Document 1

Energy Commission Staff technical comments are presented to conform with the preliminary EIS outline presented in Part 7.0, page 36 of SD1. Comments on the narrative are incorporated.

1.0 – PURPOSE OF ACTION AND NEED FOR POWER

1.2 – Need for Power

The discussion on Need for Power will form the energy and economic baseline against which future changes in energy production from the Klamath Hydro Project will be measured for potentially significant adverse effect. FERC's assessment of the Need for Power should be clearly delineated in terms of geographic scale, jurisdiction and timeframes. The appropriate frame of reference for the NEPA analysis will be PacifiCorp's service territory and the local Klamath control area. However, on an energy basis, there are many intertwined jurisdictions and geographical areas that encompass, overlap or form part of the larger frame of reference for a regional energy analysis. Inter-regional power purchase agreements and power sharing are becoming an increasingly important

[6] PRC Section 253000

[7] *2003 Integrated Energy Policy Report*, California Energy Commission, Docket No. 02-IEP-1, Publication No. 100-03-019, December 2003.

tool for meeting customer load obligations. Therefore, we recommend that the following jurisdictions be assessed, ranging from largest to smallest:

- **Western Electricity Coordinating Council (WECC) Region and Sub-Regions**: It appears that PacifiCorp's service territory includes each of the four WECC sub-regions of the Northwest Power Area, Rocky Mountain Power Area, Arizona-New Mexico-Southern Nevada Power Area, and the California-Mexico Power Area.

- **PacifiCorp's Service Territory**: Includes parts of Utah, Oregon, Wyoming, Washington, Idaho and California.

- **PacifiCorp's Western Division and Control Area**: Includes parts of Washington, Oregon and California.

- **State of Oregon**

- **State of California**

- **Local Klamath Control Area:** Control area in which the Klamath hydro project is located.

For each of these regions and jurisdictions, FERC should present and assess the following information:

- Current capacity and demand, including summer and winter peak demands, in terms of capacity and energy.

- Projected load and demand at date of license renewal (2006), and 10 years and 30 years from the date of license renewal. This assessment should include the assumptions on economic growth and energy demand changes.

- Projected changes in generation capacity, including additions, retirements, reserve margins, efficiency and demand side management. This should be presented in total and separated by fuel type (coal, natural gas, nuclear, hydro, wind, geothermal, and other renewables).

- Deliverability issues associated with current bulk transmission capacity and projected changes in transmission capacity.

Recommended Analytic Approach

The Klamath Hydroelectric project has 161 MW nameplate capacity and produces on average 656 gigawatt-hours (GWh) annually. Is there a need for the Project's power? The Need for Power issue is a subjective one that depends on the perspective of the analysis, geographic area and jurisdiction being

assessed. For example, for the WECC as a whole, there is currently about 185,000 MW of capacity, which is considered an over-supply situation. California's current capacity in summer 2004 is just under 61,000 MW. In normal weather conditions, this should be sufficient to meet peak demand, although a hot summer could push reserves below desired levels. More generation is needed in California this decade. In contrast to WECC, PacifiCorp is in a net short position, and secures about 28% of its electricity through power purchase agreements. Locally in the Klamath County area, 577 MW of new natural gas-fired capacity has been built, with another 1,600 MW in licensing review by the State of Oregon. Some of this local power is being exported to California. The question of need for the Project's power depends completely on the scope of the analysis and the perspective of the affected parties and stakeholders. Accordingly, the NEPA analysis should be precise in its assumptions on the geographic and jurisdictional scope of the analysis on Need for Power.

The time scale is also an important element in the Need for Power analysis. Currently, there is over-supply in the WECC region, undersupply in PacifiCorp's self-generation portfolio, and adequate supply in California. Through 2012, the WECC regional situation and PacifiCorp's situation will be the same, but California may be emerging from a supply shortfall, which could occur between 2005 and 2009. Afterwards, supplies are expected to be developed to meet growing demand. The need for the Project's power also depends critically on the time scale being assessed.

Changes in resource mix and generation technologies must also be factored into the need assessment. Large portions of the natural gas-fired steam fleet are expected to retire over the next 10 years. Replacement capacity will likely come from new gas-fired combined cycle and combustion turbine power plants, along with substantial increases in renewable technologies such as wind. Conservation, efficiency and demand side management are also proven methods for reducing average and peak demands. These new generation resources and conservation measures are generally cost-effective and commercially viable alternatives, although site specific costs will vary. The analysis on the need for the Project's hydropower must also encompass how different types of generation capacity and technology are considered over time.

Forecasts and Data Sources on Electricity Supply and Demand

Energy Commission Staff offer the following summary of supply-demand balance forecasts and data sources to FERC and its NEPA contractors in order to understand the range of information provided by each of the main energy jurisdictions in the Pacific Northwest and California. The WECC numbers are considered to be informative for a broad brush view of the Western U.S. energy picture, but less reliable for more localized planning and assessment. The forecasts of new generation and future supply-demand balances provided by the Bonneville Power Administration, Northwest Power Planning Council, PacifiCorp

and California Energy Commission are generally considered to be more robust and reliable.

WECC

The WECC reports that expected reserves will be adequate to meet demand on a WECC regional basis through 2012.[8] As of January 2003, generation capacity totaled 173,440 MW. About 32,000 MW in net, new generation capacity is expected to be added in the same time period (just over 38,000 MW in new capacity less about 5,800 MW in planned retirements). New generation additions are substantially lower than earlier projections. Current 2004 peak demand is 139,851 MW, which is expected to grow to 148,634 by 2007.[9]

For the Northwest Power Pool (NWPP), supplies are expected to meet winter peak demands through 2012 with margins ranging from 23 to 29 percent. This assumes demand growth rates of 1.6 percent. Current peak demand is 48,293 MW, which is expected to grow to 51,047 by 2007.

For the California Mexico Area, peak demand growth is forecast at 2.2 percent annually through 2012. Capacity margins are expected to range from 11.8 to 19.9 percent. Transmission congestion may lower capacity margins south of Path 15.

FERC should consult the following two WECC documents, and consult with WECC to obtain the most current information:

> *Western Electricity Coordinating Council 10-Year Plan Summary, October 2003*
>
> *WECC Power Supply Assessment, October 2003*

Bonneville Power Authority

The Bonneville Power Authority's (BPA) Pacific Northwest Loads and Resources Study, commonly referred to as the White Book,[10] presents annual updates of regional loads and forecasts for federal and non-federal power in the Pacific Northwest region. Energy Commission Staff consider the White Book to be one of the best energy information resources due to its clearly stated and conservative planning assumptions on dependable hydropower capacities, and the rigor with which new generation resources are scrutinized.

For the 2004 operating year (OY), BPA controls or markets a total of 20,445 MW in nameplate capacity hydropower, which correlates to 17,994 MW in peak

[8] Western Electricity Coordinating Council 10-Year Plan Summary, October 2003
[9] WECC Power Supply Assessment, Table 3a, October 2003
[10] Pacific Northwest 2002 Loads and Resources Study, Updated May 2004, Bonneville Power Administration

capacity, and 6,791 average MW (aMW) in firm energy (Part 4, Table 4). BPA contracts for another 3,091 MW in peak capacity.

For federal loads and resources between OY 2004 and 2013, BPA forecasts a resource surplus of 123 aMW for 2004, deficits less than 100 aMW from 2005 to 2008, and then increasing resource deficits that reach 464 aMW in 2013 (Table 6).

The BPA's Regional Analysis includes projected loads and energy resources for all non-federal and federal sectors in the Pacific Northwest. The White Book forecasts that loads will grow from 21,251 MW on OY 2004 to 23,867 MW in OY 2013 (Table 8, Scenario 3 – without DSI loads). The winter peak load is forecast to grow from about 35,000 MW in OY 2004 to about 39,000 MW in OY 2013 (Figure 13).

Regional resources total 39,777 MW in peaking capacity for OY 2004, derated to 23,974 aMW in firm energy (hydropower is derated from 24,361 MW peak capacity to 11,681 aMW firm energy based on BPA's low critical water year planning assumption from 1937). Firm energy resources are projected to grow to about 25,000 aMW by 2013 (Figure 14).

The BPA White Book projects regional supply-demand balances through OY 2013. As shown on Table 1 (reproduced from White Book Table 12), surpluses for the Base Case scenario will be 1,244 aMW in 2004, growing to a peak of 1,629 aMW in 2006, and then reducing steadily through 2013 with a forecast deficit of 674 aMW.

Table 1 (White Book Table 12)
Potential Variability of Regional Firm Annual Energy
Surplus/Deficit Projections Utilizing Different DSI Load Levels*
Assuming Normal Weather Conditions Under 1937-Water Conditions

Operating Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Scenario 1: Base Case: 100% Regional DSI Loads (792 aMW)	1,244	1,359	1,629	1,438	1,245	738	528	34	-157	-674
Scenario 2: 50% Regional DSI Loads (396 aMW)	1,640	1,755	2,025	1,834	1,641	1,134	924	430	239	-278
Scenario 3: No Regional DSI Loads	2,036	2,151	2,421	2,230	2,037	1,530	1,320	826	635	118

* "DSI Load Levels" refers to the power needs of the Direct Service Industries, which primarily includes the aluminum processing sector. At full operational capacity, DSI load can total 3,145 MW.

The White Book planning assumptions are conservative in that they assume dry year hydro production levels and incorporate the DSI loads, which have been decreasing or non-existent in recent years due to the energy price sensitivity of the aluminum processing industry.

The BPA White Book also uses average MW in its reporting, rather than nameplate or peak MW capacity, so care must be used to ensure comparisons are made in the same units (the apples to apples rule).

Northwest Planning and Conservation Council

The Northwest Planning and Conservation Council's (NWPCC) 5th Power Plan forecasts that average loads in the Pacific Northwest will grow from 20,080 MW in 2000 to 25,420 MW in 2025.[11] This assumes an average annual growth rate of 1 percent, which factors in load reductions through 2003 due to loss of smelter loads, and then steady increases through the rest of the period.

The resource mix is anticipated to evolve through 2025. The NWPCC anticipates 2,000 MW in new coal, 7,000 MW of new wind, 600 MW of new combined cycle natural gas plants, and 1,200 MW of other renewables. By 2025, the regional resource mix on a capacity basis would measure 62 percent hydro, 18 percent wind, 11 percent coal and 9 percent natural gas. Conservation measures are also forecast to play a role in meeting peak demands.[12]

The 5th Power Plan Demand Forecast emphasizes that planning to meet peak demands is more important than planning to meet average energy loads (page 37).

FERC should consult the following two NWPCC documents, and consult with the Council to obtain the most current information:

> *Forecast of Electricity Demand for the 5th Pacific Northwest Conservation and Electric Power Plan*,
>
> *Wholesale Power Price Forecast for the Fifth Power Plan*

PacifiCorp

PacifiCorp's Integrated Resource Plan (IRP) is an excellent planning document that describes the company's strategy to meet current and increased load over the next 20 years. One issue stressed in the IRP is the need for a flexible, adaptive strategy that can cover multiple scenarios in the power generation and transmission sector over a long planning horizon.

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[11] *Forecast of Electricity Demand for the 5th Pacific Northwest Conservation and Electric Power Plan*, Revised Draft, May 13, 2003, Northwest Planning and Conservation Council

[12] *Wholesale Power Price Forecast for the Fifth Power Plan*, Revised Draft, March 3, 2004, Northwest Planning and Conservation Council

PacifiCorp has 1.5 million customers spread across 6 western states. Average system load is 5,867 MW. The 2002 winter peak was 7,585 MW, and the summer peak reached 8,511 MW.[13] Demand is expected to grow 2 percent annually in its western service territory (in which the Klamath Project is located) and 2.2 percent in the eastern service territory. Under a medium load growth scenario of 1.3 percent, summer peak demand is projected to reach 9,875 MW in 2011.

PacifiCorp's 2003 resource mix totals 8,389 MW in nameplate capacity and 7,920 MW in net capability. The mix includes 1,067 MW of nameplate hydro, 624 MW of nameplate natural gas-fired thermal, about 7,500 MW of nameplate coal fired capacity, and 37 MW of nameplate wind energy (IRP Table 2.3).

PacifiCorp presently has 8,833 MW of nameplate capacity. The 2004 peak demand totals 10,090 MW, including a 15 percent reserve margin. PacifiCorp does not cover all of its resource needs through self generation, and secures about 28 percent of needed energy through power purchase agreements. The long term power purchase agreements include 925 MW of winter peak power from Bonneville Power Administration (BPA) (declining to 574 MW in 2004), 389 MW of winter capacity from Mid-Columbia public utilities districts, and 50 MW of wind energy from the Rock River Project in Wyoming.

According to the IRP, the gap between PacifiCorp-owned generation and peak demand will grow to about 4,100 MW by 2014, assuming loss of some hydro and coal capacity in order to meet environmental requirements, and assuming that the power purchase agreements are not renewed.

PacifiCorp's preferred approach to meet this growing demand includes the following procurements and fleet additions:

- 1,400 MW of renewable resources
- 450 MWa of DSM and 90 MW of direct load control
- 2,100 MW of baseload capacity
- 1,200 MW of peaking capacity
- 700 MW shaped resource contracts

For purposes of the NEPA analysis, it is critical not to prejudice decisions by load serving entities (LSEs) to meet some portion of their loads through power purchase agreements. This is a standard method for hedging risk and meeting demand that is practiced by nearly all investor owned and municipal LSEs. PacifiCorp recognizes that there are tradeoffs between building new generation and securing power through long and short term contracts.

> "For analytic purposes, the IRP assumes new resources are developed and owned by PacifiCorp. However, no decision has been made to invest

[13] PacifiCorp's Final License Application, Exhibit H

in specific resources. The decision to own, build and invest in a new resource versus contracting with a third party will be made as part of the procurement process for each new resource addition, and on a case-by-case basis" (IRP at 3).

Therefore, in the NEPA analysis, it cannot be simply assumed that because PacifiCorp has a net short position in self-generation, and that because this gap between self-generation and demand may grow to 4,100 MW by 2014, that the energy and capacity from the Klamath Project is critical and needed to meet customer load. In the view of Energy Commission Staff, it is the small scale of the Klamath Project's energy output in relation to varying forecasts of net energy deficits and surpluses that needs to be critically examined.

In addition, the question of how PacifiCorp got into the net short position with self-generation should be considered. Presumably, strategic decisions were made to forestall investments in new, wholly owned generation in the precursor period to energy market deregulation. This was the decision made by California investor owned utilities in the late 1980s and1990s: forestall new investments by the regulated utilities until the new wholesale markets are established, and shift investment to the non-regulated affiliates in order to develop merchant power. PPM, Scottish Power's non-regulated affiliate to PacifiCorp, has invested in and developed numerous merchant plants in the PacifiCorp service territory in order to tap the merchant power wholesale market in California and elsewhere. This is not intended as a critique of PacifiCorp's investment and strategic planning decisions. Rather, it is intended as further context on supply-demand balances and procurement strategies in a period of energy market transitions.

California

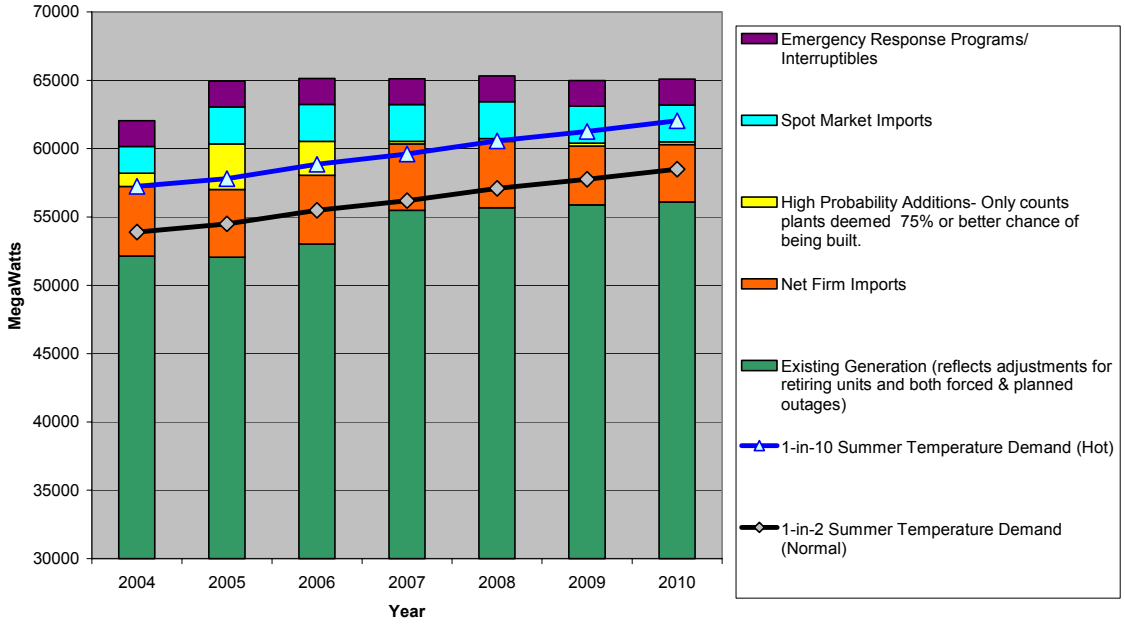
The Energy Commission Staff's current *2004 Electricity Supply and Demand Outlook* indicates that supplies are adequate to meet demand in a normal weather condition with a 12.8 percent operating reserve. The expected 2004 August peak demand is estimated at 53,896 MW. Factoring in reserve margins, summer peak is estimated at 60,898 MW. Under a hot weather scenario (1-in-10 year temperatures), reserves may drop as low as 5.6 percent, which would trigger implementation of emergency programs. [14]

For the 2004-2010 period, reserve margins may fall below 5 percent under hot temperature conditions in 2007, which is a matter of concern to the Energy Commission and other energy agencies. New resources are needed between 2005 and 2008 to maintain system reliability. While 6,397 MW of new capacity is expected to come online during the 2004-10 period, a number of older natural gas-fired steam units are expected to retire. Resource procurement activities LSEs and merchant generators are expected to respond to these generation

[14] *California's Summer 2004 Electricity Supply and Demand Outlook,* California Energy Commission Staff Staff Report No. 700-04-005, June 2004.
Available at http://www.energy.ca.gov/reports/2004-06-03_700-04-005.PDF

shortfalls by adding new capacity in 2009 and beyond. Figure 1 and Table 2 illustrate the California supply – demand balance between 2004 and 2010.

Figure 1
2004-2010 Statewide
Electricity Supply/Demand Outlook
California Energy Commission



Additional California reports include:

California Energy Commission 2002-2012 Energy Outlook

California Independents System Operator 2003 Report

Table 2
2004 - 2010 Statewide Supply/Demand Outlook
California Energy Commission

Line		Aug 2004	Aug 2005	Aug 2006	Aug 2007	Aug 2008	Aug 2009	Aug 2010
1	**Existing Generation**	**56,479**	**56,862**	**57,814**	**58,530**	**58,896**	**59,605**	**59,810**
2	**Forced and Planned Outages** [1]	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**
3	**Retirements** [2]	**-601**	**-1,091**	**-2,385**	**0**	**0**	**0**	**0**
4	**Net Firm Imports** [1,3]	**5,095**	**4,948**	**5,048**	**4,848**	**4,848**	**4,315**	**4,209**
5	**High Probability CA Additions**	**984**	**2,043**	**3,101**	**366**	**709**	**205**	**198**
6	**Spot Market Imports**	**1,950**	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**	**2,700**
7	**Total Supply (MW)**	**60,157**	**61,712**	**62,528**	**62,694**	**63,403**	**63,075**	**63,167**
8	**1-in-2 Summer Temperature Demand (Normal)**	**53,896**	**54,500**	**55,487**	**56,195**	**57,090**	**57,757**	**58,491**
9	**Projected Operating Reserve (1-in-2)** [4]	**12.8%**	**14.6%**	**14.0%**	**12.7%**	**12.1%**	**10.0%**	**8.6%**
10	**Proj. Op. Reserve (1-in-2) w/ Accelerated Programs** [5]	**13.3%**	**16.9%**	**17.9%**	**18.4%**	**18.7%**	**17.3%**	**16.5%**
11	**1-in-10 Summer Temperature Demand (Hot)**	**57,247**	**57,811**	**58,858**	**59,609**	**60,559**	**61,266**	**62,044**
12	**Projected Operating Reserve (1-in-10)** [4]	**5.6%**	**7.4%**	**6.8%**	**5.6%**	**5.1%**	**3.2%**	**1.9%**
13	**Proj. Op. Reserve (1-in-10) w/ Accelerated Programs** [5]	**6.3%**	**9.2%**	**10.1%**	**10.5%**	**10.7%**	**9.4%**	**8.7%**

14 Notes: [1] Forced and Planned Outages and Net Firm Imports are estimated based on historic data. [2] In 2005 and 2006 there are respectively 750 MW and 1250 MW of generic retirements to reflect capacity deemed to be at risk for retirement. In addition, CEC recognizes that South Bay Units 1-4 will retire prior to the summer of 2009. However, since these units are needed for reliability, we assume these plants' capacity will be replaced without interruption. [3] No new Net Firm Imports are assumed, so contract expirations reduce Net Firm Imports over time with exception of 2006 when 100 MW export contract expires. This causes Net Firm Imports to increase by 100 MW in 2006. [4] These reserves do not consider potential capacity additions derived from price responsive demand programs adopted by the CPUC, incremental new renewables from Energy Action Plan or High DSM Peak Demand Reduction Scenario. [5] Includes potential capacity additions from Energy Action Plan or High DSM Peak Demand Reduction Scenario. [6] Of the 1,167 MW generation was mothballed (removed) in Nov 2003, Etiwanda 4 (320 MW) comes back online 15 July 2004; and Etiwanda 3 (320 MW) comes back online 15 Sept 2004. [7] Emergency Response and Interruptibles programs are not included in operating reserve calculations.

15	**Capacity from Plants on Cold Reserve Status** [6]	**847**	**527**	**527**	**527**	**527**	**527**	**527**
16	**Emergency Response Programs/Interruptibles** [7]	**1,885**	**1,885**	**1,885**	**1,885**	**1,885**	**1,885**	**1,885**

Local Klamath County Area

Load for the local Klamath County area may be about 750 GWh per year.[15] The Klamath Hydro Project produces on average 656 GWh per year, which would comprise 87 percent of local load if it were the only available energy resource. According to the Oregon Department of Energy (Oregon DOE) Website,[16] PacifiCorp's PPM subsidiary has built a new 484 MW cogeneration natural gas plant and a 93 MW combustion turbine peaker project in Klamath Falls. The cogeneration plant is owned by the City of Klamath Falls. At a 90 percent capacity factor, the cogeneration plant would generate 3,800 GWh annually. Two additional combined cycle natural gas plants totaling 1,600 MW are proposed in southern Oregon and are undergoing licensing review by Oregon DOE. PPM's 543 MW Klamath Generation Project is expected to be licensed by the end of 2004, while COB's 1,150 MW project is in the "contested evidentiary" phase.

A good portion of the merchant plant energy from the Klamath County area is being purchased by Seattle City Light, and numerous California municipal utilities, including the Sacramento Utility District and Modesto Irrigation District.

Considering Retirements and Needed Resource Additions

The retirement of inefficient, non-economic generation facilities is a standard feature of the life cycles and business cycles in all sectors of the power generation industry. As cited in an earlier section, the WECC forecasts the retirement of about 5,800 MW in natural gas-fired steam generation capacity by 2012. In California, 950 MW of steam generation were retired between 2000 and 2003, while 4,077 MW of steam generation capacity are expected to retire or go into "mothball status" between 2004 and 2006.

Using the simplistic logic "all capacity is critical" would result in older, inefficient units being kept in service even if it does not make economic or environmental sense. Older units tend to remain in service as long as they are economic; capacity payments or Reliability Must Run contracts such as offered by the CAISO can offset the higher heat rates and higher fuel costs associated with older units, while new environmental regulatory requirements could render older units non-economic. In assessing the need for power in the Western U.S., it is the view of Energy Commission Staff that hydropower in the "low power – high impact" category be evaluated as candidates for the retirement side of the ledger, rather than be maintained regardless of the economic and environmental costs.

[15] *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, California Energy Commission Staff Report

[16] *Oregon's Energy Facilities*, Oregon Department of Energy Website, "," http://www.energy.state.or.us/siting/facility.htm, Reviewed April 19, 2004.

Considering Energy Needs and Not Just Capacity Issues

In considering the Need for Power and supply-demand balances in the WECC, NWPP, PacifiCorp service territory, and California, it is more accurate to examine the types of energy needed, and not simply a summary of capacity balances. In other words, what are the winter and summer peak demands? What are the needs for baseload and load following energy? Can the potential loss of the Klamath Hydro Project's peaking, load following and flat energy be readily replaced? For the Northwest and California, meeting peak demands is the key to reliability planning and electric resource adequacy. There is sufficient flat and load following energy to meet those parts of the demand curve. Meeting peak demand is also dependent on electric transmission line capacity.

4.0 – DEVELOPMENTAL ANALYSIS

4.1 – Power and Economic Benefits of the Proposed Project

Energy Commission Staff provided extensive comments to FERC on PacifiCorp's Final License Application (FLA) and on how the energy values and valuation of Project energy were characterized. FERC and its contractors should review and incorporate the FLA comments during the NEPA analysis. In summary, the key issues raised are:

1. **Clarify and Confirm the Klamath Project Operations and Peaking Power Generation**: The FLA states that Project energy is 64 percent peaking production (447,209 MWh annually) and 36 percent baseload production (249,834 MWh annually). However, Project operations are constrained by water availability from the U.S. Bureau of Reclamation's releases from the irrigation project. The peaking power production should be clarified and confirmed on an annual, seasonal and time of day basis.

2. **Clarify and Confirm PacifiCorp's Market Price Valuation of Klamath Energy:** The FLA states that the value of Klamath Project power should be $70 per MWh and $48.5 million annually in 2003 nominal dollars. This figure is calculated from a mix of peak and non-peak prices from the Mid-Columbia and California Oregon Border hubs. Energy Commission Staff stated that "We cannot confirm that these figures are appropriate for use as the critically important valuation estimate for the project's energy."

   Energy Commission Staff provided a range of wholesale cost forecasts from the Northwest Power and Conservation Council and PacifiCorp, and a series of avoided cost valuations for California hydropower projects in FERC relicensing.

   "The Energy Commission Staff presents these four different market estimates of wholesale electric costs and project-specific avoided costs in order to provide a comparative range of current replacement energy costs for the Klamath Hydroelectric Project. The Northwest Power and Conservation Council estimates long-term levelized costs of power at the

mid-Columbia trading hub at $36.50 / MWh in year 2000 dollars. PacifiCorp's Oregon PUC Avoided Cost Filing shows 2004 peak energy prices at $28.74 and off-peak prices at $24.60 / MWh. The same filing estimates total avoided costs for 2004 to range between $26.71 and $27.28 / MWh. PacifiCorp's Integrated Resource Plan (Table C26) estimates 2004 flat energy prices at the mid-Columbia hub to be $33.35, while California-Oregon Border hub prices are estimated at $35.16.

The Energy Commission's consultant report estimating avoided costs for 26 California hydroelectric projects of widely varying capacity, peaking capability, pondage and provision of ancillary services shows a range of avoided costs from $27 to $45 / MWh for 23 projects."

3. **Non-Conformance with FERC's Mead Paper Decision:** FERC's Mead Paper decision specifies that only current energy replacement costs should be used in order to avoid controversies about cost escalation or discounting.[17] This emphasis on current energy replacement costs is also known as the "current cost method." As FERC stated in its 2003 Draft EIS on the Davis Dam in Alaska:

> "As articulated in Mead Corporation, Publishing Paper Division (72 FERC 61,027), the Commission's approach to evaluating the overall economics of a hydroelectric project uses current costs to compare the costs of the project and likely alternative power. We consider the power benefit of the project to be equal to the current cost of the alternative source of power that would be used in the absence of the project. We use a 30-year period of analysis with no forecasts of potential future inflation, escalation, or deflation to convert all costs to a levelized annual value. The levelized annual value is a convenient metric for comparing a cost to a resulting benefit, whether the benefit is measured in dollar-value or non-dollar-value terms."[18] (Emphasis added.)

Energy Commission Staff recommend that FERC prepare a valuation estimate using its own guidelines, and a second one that conforms to PacifiCorp's methodology of using standard inflator and escalation assumptions.

4.2 – Power and Economic Benefits of the Staff-Recommended Alternative

All descriptions of power and economic benefits of the Staff Alternative should conform to the comments and recommendations of Energy Commission Staff as stated for Section 4.1 and in the FLA comments.

[17] FERC Order Issuing New License, FERC Project No. 2506, Mead Paper Corporation, July 13, 1995.

[18] Draft Environmental Impact Statement for the Glacier Bay National Park and Preserve: Falls Creek Hydroelectric Project and Land Exchange (P-11659), October 2003.

The SD1 narrative on page 23 states that: “To the extent that modifications would reduce the power production of the proposed project, we will evaluate costs and contributions to airborne pollution related to generation of replacement power by fossil fuel stations.”

Energy Commission Staff recommend that replacement energy scenarios be developed in accordance with the loading order for the California Energy Action Plan: 1) energy efficiency and conservation measures; 2) development of renewable energy resources; 3) development of new thermal generation resources, including strategic use of natural gas-fired peakers. The assumptions on heat rates, pollution controls and emissions levels should be clearly and transparently presented. The actual energy values being replaced should be analyzed, and not just a standard capacity replacement case. In other words, the seasonal peak, load following and flat energy values being replaced should be clearly defined in the assumptions. The planning horizon for securing replacement energy for the Klamath Hydroelectric Project, should it be decommissioned, also needs to be factored into the analysis.

4.3 – Retirement of Additional Developments

The SD1 narrative on page 23 states that “We will assess retiring additional developments … without project dams in place, to address resource issues identified in the analysis.”

As stated in the Energy Commission Staff’s comments on the FLA:

> “The Energy Commission’s primary recommendation to FERC - based on our understanding of the energy and biological resources associated with the Klamath Hydro Project - is that decommissioning may be a viable option given that the Project is a small energy facility with 161 MW total capacity and annual average production of 656 GWh. Consequently, decommissioning should be developed and fully evaluated as an alternative during federal review of PacifiCorp’s application in accordance with the National Environmental Policy Act. We note that low power – high impact energy facilities can create substantial net environmental benefits if decommissioning proves to be feasible and cost-effective, and if replacement energy is available.”

Energy Commission Staff recommend, at a minimum, two decommissioning scenarios:

1. Removal of Iron Gate dam and powerhouse with the addition of volitional fish passage past the Copco dams.

2. Removal of the California dams and powerhouses with addition of volitional fish passage past Keno.

For the Oregon dams, we recommend that FERC consider input from Oregon agencies and stakeholders regarding the formulation of alternatives for potential decommissioning of dams in Oregon.

In analyzing the costs and benefits of the decommissioning scenarios, the NEPA analysis should develop clear assumptions and estimates for the following costs:

- Costs of dam, powerhouse and sediment removal
- Costs of volitional fish passage measures
- Costs of channel and river channel restoration
- Cost of foregone generation
- Additional changes in operations of the Bureau's irrigation project needed to improve water quality and flow volumes to optimize salmonid fisheries restoration

The NEPA analysis should also develop clear assumptions and estimates for the following benefits:

- Amounts of salmonid habitat made available
- Productivity increases in salmonids due to increased access to habitat
- Restored salmonid fisheries for tribes
- Recreational fishing and tourism
- Commercial fishing
- Decreases in ESA compliance costs for other stakeholders due to the increases in endangered salmonid populations

CALFED / DWR Fish Passage and Dam Removal Programs – Bulletin 250

The California Bay Delta Authority (CALFED) and Department of Water Resources (DWR) manage California's fish passage improvement program. Part of the program includes assessing the feasibility of dam removal as a tool for restoring fish passage for endangered runs of salmonids. According to the Bulletin 250 program description, 28 dams have been removed in California between 1990 and 2000, many of which have resulted in positive salmonid population increases.[19] Larger dam removal assessments and decommissioning planning are underway for a non-power dam on the San Clemente River in Monterey County, and for power dams on the Yuba River (Engelbright Dam), Battle Creek, and Butte Creek. The Battle Creek Restoration Project is a $28 million program currently scoped to remove five dams and restore 42 miles of anadromous fishery habitat.

[19] Bulletin 250-2002, Public Review Draft of the Fish Passage Improvement Program, California Department of Water Resources and CALFED, February 2003, available at http://www.isi.water.ca.gov/fish/ChapterFront/Front%20Matter.pdf

Decommissioning of the 126-foot high Matilija Dam on Matilija Creek in Ventura County, California would constitute one of the nation's largest dam decommissioning projects. The $110 million decommissioning and restoration project includes the removal or management of 2.1 million yards of sediment. Goals for dam removal and river restoration include improving water quality in downstream reaches and improving habitat conditions for the southern most ecologically significant unit (ESU) for the endangered Southern Steelhead. This decommissioning project is not a CALFED or DWR project.

5.0 – [FERC] STAFF'S CONCLUSIONS

5.2.7 – Socioeconomic Resources

The SD1 narrative on page 30 states that the analysis will assess, "The effects of potential dam removal on the socioeconomic conditions of communities influenced by the project."

Energy Commission Staff assume the assessment will include positive and negative effects on the influenced communities. The positive effects should include the stakeholders and communities listed above in our comments on Section 4.3.

5.2.9 – Developmental Resources

The effects of proposed protection, mitigation and enhancement measures on project economics should incorporate of the pertinent Energy Commission Staff comments on proper valuation of the Klamath Hydro Project's energy.

5.2.10 – Consistency with Comprehensive Plans

Energy Commission Staff urge FERC to add two California energy plans to the list of approved comprehensive plans. These are the Integrated Energy Policy Report and the Energy Action Plan.

In the fall of 2002, the California Legislature passed the Integrated Energy Policy Act (Senate Bill 1389). This Act directs the Energy Commission to prepare a biennial ***Integrated Energy Policy Report*** (Energy Report) for submission to the Governor and Legislature. The Act also states that information contained in the Energy Report will form "the foundation of energy policies and decisions affecting the state."[20] The 2003 Energy Report was adopted by the California Energy Commission on November 12, 2003, and has been submitted to the Governor's Office.

Energy Action Plan

The Energy Action Plan was developed and adopted in 2003 by the California Public Utilities Commission, California Energy Commission and California Power Authority.[21]

[20] PRC Section 253000

[21] Available on the CPUC website at http://www.cpuc.ca.gov/PUBLISHED/REPORT/28715.htm

"The goal of the Energy Action Plan is to:

> Ensure that adequate, reliable, and reasonably-priced electrical power and natural gas supplies, including prudent reserves, are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound for California's consumers and taxpayers.

The energy agencies intend to achieve this through six specific means:

- Meet California's energy growth needs while optimizing energy conservation and resource efficiency and reducing per capita electricity demand.
- Ensure reliable, affordable, and high quality power supply for all who need it in all regions of the state by building sufficient new generation.
- Accelerate the state's goal for renewable resource generation to 2010.
- Upgrade and expand the electricity transmission and distribution infrastructure and reduce the time before needed facilities are brought on line.
- Promote customer and utility owned distributed generation.
- Ensure a reliable supply of reasonably priced natural gas."